99-D-125, Replace Boilers and Controls, Kansas City Plant Kansas City, Missouri

(Changes from FY 1999 Congressional Budget Request are denoted with a vertical line [|] in the left margin.)

Significant Changes

| # This project was planned to start in January 1999, but did not begin until October 1999 because of the period of the congressionally mandated independent assessment of this
| project. Because of this delay, the Total Estimated Cost has increased from $14 million to
| $14.3 million to reflect escalation costs, and the Total Project Cost increased from $14.4 million to $15.0 million due to escalation and the application of burden to other project costs (OPC) which were omitted in the original cost estimate.

1. Construction Schedule History

	Fiscal Quarter				Total Estimated Cost ($000)	Total Project Cost ($000)
	A-E Work Initiated	A-E Work Completed	Physical Construction Start	Physical Construction Complete		
FY 1999 Budget Request *(Preliminary Estimate)*	2Q 1999	4Q 2000	4Q 2000	4Q 2002	14,000	14,400
FY 2001 Budget Request *(Current Baseline Estimate)*	1Q 2000	2Q 2001	2Q 2001	4Q 2003	14,300	14,977

2. Financial Schedule

(dollars in thousands)

Fiscal Year	Appropriations	Obligations	Costs
1999	1,000	1,000	1,000
2000	0	0	0
2001	13,000	13,000	5,800
2002	300	300	6,900
2003	0	0	600

3. Project Description, Justification and Scope

This project will renovate and upgrade the existing steam generating facility located at the West Boilerhouse. This project removes four 100,000 PPH (Pound per Hour) boilers, boiler control panels and boiler annunciator panels, water softeners, polisher, pumps, forced draft fans, deaerator, piping, controls, and other existing ancillary boiler support equipment, and replaces them with new equipment including new microprocessor-based control panels and a boiler control room containing annunciator panels and system status indicators, in the same general location. The project will essentially be a one-for-one replacement with slightly reduced overall generating capacity; it will provide system improvements to reflect current technology.

The new boilers will be designed to efficiently and cleanly burn natural gas or No. 2 fuel oil. The burner assembly will contain a ring for natural gas and main and auxiliary fuel oil guns. The main fuel will be natural gas with No. 2 fuel oil as backup. Automatic and continuous blowdown systems, stack opacity monitoring, oxygen monitoring, steam, gas, and oil flow meters, draft fans, drum level fuel and draft controls will be included as well as feedwater pumps and a deaerator. The boiler controls will be microprocessor-based direct digital and will include all safeties. The system is to come complete with heat recovery equipment and controls that are technologically and economically feasible such as economizers and blow down heat recovery. A method to protect the boiler when off line will also be included. Low nitrogen oxide burners will be evaluated, and continuous environmental monitoring of nitrogen oxide and sulphur dioxide will be included as required by the 1990 revisions to the Clean Air Act.

Controls work will consist of the replacement of control components, boiler control panels, annunciator panels in the control room, and installation of a system schematic wall. Control valves will be installed on feedwater, natural gas and fuel oil, and will include positioners, air locks and limit switches. A vortex meter will be installed on each natural gas line. Self-calibrating opacity monitors will be installed on the stacks and continuously monitor stack conditions. The oil, gas trains, and boiler installation will be designed in compliance with National Fire Protection Association (NFPA) 8501.

The equipment in the control room will consist of an industrial grade console computer system, with a high resolution color monitor, laser printer and data logger. The computer will be supplied complete with software, manuals, graphics and reporting capabilities and efficiency calculations.

The control room will include a floor to ceiling wall panel showing schematics of the boilerhouse steam system. This schematic will use replaceable color tiles and LEDs or a projection screen near each piece of equipment to show equipment status on items such as pressure, temperature and flow. The control room will contain two work stations to control the boilers. The work stations will contain multiple computer screens to display alarms and the boilers operating conditions. The screens will be touch sensitive to acknowledge the alarms.

The following items have been considered and will not be included as part of this project:

- <u>Cogeneration:</u> Several previous studies have determined that cogeneration under the existing natural gas and electricity rates is not economically feasible.
- <u>Tempered Water System:</u> It is not currently planned to provide any interface and/or connection between the steam and tempered water system as a part of this project; this project will not include the use of chiller recovered heat as combustion air preheat.
- <u>Number 6 Fuel Oil:</u> The project will not provide the capability to fire on Number 6, (residual) fuel oil due to lack of local availability and environmental concerns with this fuel. It is believed that the availability of Number 2 fuel oil is sufficient.
- <u>Building Ventilation:</u> This project is going to locate equipment on the induced draft fans fan deck which is normally significantly above ambient temperatures. The existing building operable louvers and windows, as well as the existing Boilerhouse roof exhaust fans, will provide sufficient ventilation and combustion air. The "Chilled Water System Replacement" project has completely separated the chiller's room from the boiler's room by walls and doors. Each resulting building now has an emergency ventilation system independent of the other. The decrease in boiler size will help decrease the indoor ambient air temperatures.

The old boilers will be dismantled and removed in pieces. The overhead door on the west side of the West Boilerhouse will be removed ;and replaced with masonry compatible with the existing building. A new permanent wall opening will be created to facilitate the removal of the scrap boilers and to allow the new, factory assembled boilers and other ancillary equipment to be moved into place. Equipment located in the basement will be moved via the well opening on the southwest corner of the building.

The project is planned to start in the early spring with construction to be staged so that steam production to the plant will not be interrupted for significant periods of time. The general plan will be to remove two boilers from either the north or south end of the building, install two new boilers and bring them on line, then remove and replace the other two boilers. Preparatory work such as construction of the new steam headers, deaerator, feedwater piping and work on other support systems will be done to the extent possible before demolition of the boilers begins.

Energy Conservation Analysis

An economizer will be included in this project to preheat the feedwater. This system will reclaim heat from the boiler exhaust steam to heat the feedwater before it enters the deaerator.

Blow down heat recovery will be included in this project. Heat exchangers will recover heat from the blow down water. This heat will be used to preheat the make up water.

During Title I design, variable frequency drives (VFDs) will be evaluated for use with the induced draft fans. The use of VFDs will be based on Life Cycle Cost Analysis and design issues.

Background

The West Boilerhouse at the Department of Energy (DOE), Kansas City Plant (KCP), provides steam for heating, humidity control, and manufacturing processes for tenants of the Bannister Federal Complex. These tenants include the DOE, the General Services Administration (GSA), the Internal Revenue Services (IRS), the Federal Aviation Administration (FAA), the Department of Agriculture (DOA) and the Marine Corps. The steam from this boilerhouse is the only available source of heat for all of these tenants.

Although originally rated at 100,000 pounds per hour, the existing boilers can only achieve 80,000 to 90,000 pounds per hour for any sustained period of time due to their age and deteriorated condition. The boilers are unreliable, mechanically deteriorated, technologically obsolete, and spare parts are not readily available. These boilers must be replaced if the reliability of the steam plant is to be assured.

The bulk of steam generated by these boilers is consumed by the DOE's KCP in meeting its critical Defense Programs (DP) mission. However, the other Federal tenants have critical loads of their own, for which they reimburse the DOE based on memoranda of understanding with DOE.

The boilers were installed in the early 1970's (completion of project in 1974), under a contract administered by GSA. The GSA procedure was to issue a contract to a General Contractor who in turn purchased boilers, burners, controls and accessories and assembled these components on site to provide a complete and working system. The GSA specified system performance and did not detail or specify individual component parts such as burners and controls. To minimize cost and expedite construction, the forced draft fans from the original 1942 boiler system were reused in the installation. The general contractor had no previous experience with plant steam systems and/or boilers. This less than ideal situation was further aggravated when the general contractor went into bankruptcy about two-thirds of the way through the contract. GSA provided additional funds to assure the completion of the project, however, since this was going to be the contractor's last job and all profits were to go to the bankruptcy proceeding, there was little incentive for quality work.

According to both the boiler manufacturer, Riley Stoker, and the burner manufacturer, Peabody Engineering, the contractor's choice of burners was not sanctioned or approved by either manufacturer for installation on an "A" type Riley boiler. As a result of this situation, there have always been problems with the operation of the boilers. These problems have included flame impingement, incomplete combustion of fuel and other systemic problems. Throughout the period since the boilers were started up, the KCP has repeatedly had both Riley and Peabody on site and have made numerous changes to the boilers and controls in an effort to provide efficient and reliable operation. These efforts have only been partially successful.

The boilers, as originally provided, were set up and equipped to burn natural gas as the primary fuel and number 6 fuel oil, a residual fuel, as backup. However, according to Riley Stoker, the boilers were not fabricated with the intended capability to burn any fuel that left a residual deposit. As a result of this, fly ash built up in the combustion chamber during periods when the boilers were fired on number 6 fuel oil. This problem was aggravated by the fact that the poor burner selection resulted in flame impingement and incomplete combustion which increased the problem of fly ash production.

The following problems necessitate replacement of the existing system:

 # Tube Failure

All four boilers in the West Boilerhouse have had a history of excessive tube failure. The fly ash residue created by the poor selection of burners has permeated the refractory in the bottom of the boilers so that over a period of time the tubes in the bottom of the boilers and at the tube connection to the mud drum were packed with the fly ash. Fly ash by nature is hygroscopic and any introduction of moisture, whether from airborne moisture or tube leaks, rapidly finds its way to the fly ash. This fly ash produces an acid compound that attacks the exterior of the tubes. Moisture is trapped between the refractory and the tubes. Historically, the tube failures in these boilers have in almost all cases been in locations where the tube is buried in refractory.

The history of tube failures began almost at the boiler start up. The rate of failure has accelerated so that since 1992, over 2,000 tubes have been replaced in the four boilers. Between 1991 and 1995 there have been eleven separate occurrences of boiler tube leaks with an average down time per lead of between one and two months. A project to retrofit the burners so that number 2 fuel oil is used as the backup fuel was completed in the late 1980's. This has reduced fly ash buildup, but does little to repair already damaged tubes or reduce the residual fly ash in the refractory left by years of using number 6 fuel oil.

 # Refractory Problems

The boilers have also experienced a history of refractory failure. The refractory on the front section of the boilers was originally poured in place and cured while the panel was in a horizontal position. When the refractory was cured, the panel was erected and connected to the boiler body. This procedure has not proven go be satisfactory and is no longer used by Riley Stoker. Over time the front refractory separated from the boiler wall and allows flames to enter the space between the refractory and the boiler shell. The front refractory has been repeatedly repaired on all four boilers. New methods of refractory application have been developed which have reduced but not eliminated the problem. Refractory tile at the throat of the burners are also a maintenance problem and have to be replaced repeatedly.

 # Controls & Air Emissions

The controls for these boilers were technologically obsolete when the system was originally installed. The boiler controls are electro-pneumatic technology. The new standard for boiler controls that was making rapid transitions into the industry when the boilers were installed in 1974 was all electric/electronic based controls. The controls, when they were installed on the

Kansas City Plant boilers, were the last generation of old, electro-pneumatic technology produced by Hays Republic, the controls manufacturer. Hays Republic has not been able to furnish replacement repair parts for many of the control components since the mid-1980's. It is becoming increasingly difficult to find repair parts and it is estimated that within 5 years, no spare parts will be available. The controls have deteriorated and now drift from the control set point and require continuous resetting. Because of the age and condition of the controls, failure of component parts is common. These failures can and often do alter the combustion process to the point that air emissions are outside KCP's permitted values. Failure of a control component in 1992 caused an out of compliance condition on opacity (visual emissions), which resulted in a notice of violation being issued by the city of Kansas City, Missouri. The KCP air emissions are permitted by the Kansas City Air Board and must meet Federal EPA Regulations (40 CFR 60, Appendix B, Sec. 1.), Missouri State Regulation (10 CFR 10-2/06), and Kansas City, Missouri Regulations (section 18.86.D). It is predicted that without new controls, the existing boilers will experience repeated out of compliance conditions as the existing controls continue to age and malfunction.

**#	Deaerator**

The existing deaerator was installed during the 1970's. The deaerator removes dissolved gases, primarily oxygen, from the feedwater prior to it entering the boilers. This process protects and prolongs the life of boilers and piping system. There is a very limited capability to fire the boilers if this unit is out of service. The deaerator has experienced accelerated deterioration that has repeatedly required work to repair chemical stress cracking to the unit. The corrosion in the deaerator has gotten to the point where frequent repairs are necessary. In the event of a failure of this component, prolonged firing of the boiler on untreated water would significantly damage the already deteriorated boilers and piping systems.

**#	Ancillary Problems**

In general the ancillary equipment such as piping, softeners, polishers, fans and pumps is in a deteriorated condition. Maintenance on this equipment is increasing with mean time between failures decreasing. All systems have obsolete technology and the acquisition of repair parts continues to be a problem – especially for the boiler feedwater pumps and softener controls.

**#	Implications**

The existing boilers are deteriorated beyond a point where normal repair and maintenance is cost effective, reliability of the steam plant cannot be assured. Repairs of the boilers and ancillary equipment would require replacement components and many exact replacements are no longer available. It will require significant engineering design support to retrofit other components in areas where original replacements are not available.

Significant deterioration to boiler tubes and internals is so extensive that the only adequate repair would be a complete tube replacement. This would be very costly and would not put the boiler in a like new condition. Release of industrial waste from a ruptured pipe wold most likely enter the plant sanitary sewer system. This occurrence would cause the plant to be in violation of permit.

If a reliable steam supply is to be maintained, it is essential that these boilers be replaced as soon as possible. Failure to replace the existing boilers will subject the KCP to an unacceptable risk of inadequate and unreliable steam supply.

Project Milestones:

FY 2000:	A-E Work Initiated	1Q
FY 2001:	A-E Work Completed	2Q
	Construction Start	2Q
FY 2003:	Physical Construction Complete	4Q

4. Details of Cost Estimate

	(dollars in thousands)	
	Current Estimate	Previous Estimate
Design Phase		
Preliminary and Final Design costs (Design Drawings and Specifications)	626	613
Design Management Costs (0.7% of TEC)	102	100
Project Management Costs (0.08% of TEC)	12	11
Total, Design Costs (5.2% of TEC)	740	724
Construction Phase		
Utilities	10,968	10,738
Inspection, Design and Project Liaison, Testing, Checkout and Acceptance	392	384
Construction Management (1.2% of TEC)	166	163
Project Management (0.6% of TEC)	81	79
Total, Construction Costs (81.2% of TEC)	11,607	11,364
Contingencies		
Design Phase (0.7% of TEC)	97	95
Construction Phase (13.0% of TEC)	1,856	1,817
Total, Contingencies (13.7% of TEC)	1,953	1,912
Total, Line Item Costs (TEC) [a]	14,300	14,000

[a] The Conceptual Design Report was completed in February 1997. Escalation is calculated to the midpoint of each activity. Escalation rates were taken from the FY 1999 DOE escalation multiplier tables. Overhead rates were calculated at a factor of 14% for procurement and 77% for internal labor.

5. Method of Performance

Design and inspection will be performed under a KCP negotiated architectural-engineering contract. Construction will be accomplished by fixed-price contract awarded on the basis of competitive proposals and administered by Allied Signal.

6. Schedule of Project Funding

(dollars in thousands)

	Prior Years	FY 1999	FY 2000	FY 2001	Outyears	Total
Project Cost						
Facility Cost						
Design	0	0	700	137	0	837
Construction	0	0	300	5,663	7,500	13,463
Total, Line item TEC	0	0	1,000	5,800	7,500	14,300
Total, Facility Costs (Federal and Non-Federal)	0	0	1,000	5,800	7,500	14,300
Other Project Costs						
Conceptual design cost	40	0	0	0	0	40
NEPA documentation costs	11	0	0	0	0	11
Other project-related costs	103	106	106	150	161	626
Total, Other Project Costs	154	106	106	150	161	677
Total, Project Cost (TPC)	154	106	1,106	5,950	7,661	14,977

7. Related Annual Funding Requirements

(FY 2003 dollars in thousands)

	Current Estimate	Previous Estimate
Annual facility operating costs [a]	0	0
Annual facility maintenance/repair costs	10	10
Total related annual funding (operating from FY 2003 through FY 2032)	10	10

[a] Estimated life of project–30 years.